BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2015 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast (U39E).	A.14-05-024 (Filed May 30, 2014)

RESPONSE OF THE COUNTY OF LOS ANGELES TO OPTIONAL HOMEWORK ASSIGNMENT IN PREPARATION FOR THE MARCH 8 WORKSHOP ON PCIA REFORM

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For the County of Los Angeles

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I. INTRODUCTION

Los Angeles County (the County) provides the following responses to the "optional homework assignment for the Power Charge Indifference Adjustment (PCIA) Workshop participants" circulated to interested parties by California Public Utilities Commission ("Commission" or "CPUC") Energy Division staff on January 22, 2016. In accordance with Commission Decision ("D.") 15-12-022, the Commission plans to convene a workshop to discuss PCIA reform. This workshop is presently scheduled from 10 AM to 3 PM on March 8, 2016.

The County provides these responses to Energy Division staff and the instant proceeding's service list to work towards various substantial reforms necessary in light of the significant load forecasted to depart to CCA service in the near term.

II. RESPONSES TO "OPTIONAL HOMEWORK ASSIGNMENT FOR POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA) WORKSHOP PARTICIPANTS"

A. Question 1: Please indicate your understanding of how the PCIA is calculated, identifying, in as much details as possible, each input to that calculation.

The PCIA is a component of the Cost Responsibility Surcharge (CRS); the latter was originally established in 2002 (D.02-11-022) as a mechanism that ensures bundled customers remain "indifferent" to departing load. It does so by continuing to charge departing load customers for their share of any unavoidable above-market power procurement costs incurred on their behalf by the the Investor Owned Utilities (IOUs). The PCIA was introduced in 2006 (D.06-07-030) as a replacement for the DWR power charge component of the CRS, and applied to CCA customers in in 2007 (D.07-01-025). It is calculated as part of the Energy Resource Recovery Account (ERRA) proceedings.

1. PCIA Methodology

The PCIA maintains the concept of indifference established in the original CRS and estimates the forward year above- or below-market cost of the total IOU portfolio of supply resources procured prior to customer departure. The PCIA is calculated in the following manner:

$$PCIA = (TPC - MPB) - CTC$$

Where TPC is the utility's Total Portfolio Cost, MPB is the Market Price Benchmark, the difference (MPB – TPC) is also known as the "indifference amount", and the CTC is the Competition Transition Charge[1].

If the indifference amount is positive, the IOU's portfolio costs are forecasted to be "above market" for the coming year; forecasted IOU collection of PCIA charges from CCA customers are subsequently subtracted from bundled service revenue requirements. In the event that the PCIA calculation results in a negative indifference amount, these funds are tracked and carried over to offset future positive indifference amounts in future years.

[1] The CTC was authorized in Pub. Util. Code § 367(a)(1) – (6) and is intended to recover stranded costs from deregulation. It primarily consists of the above market costs (i.e. those above the MPB) of power contracts that pre-date deregulation. The CTC is quite small and is paid by all customers, bundled or unbundled. It is subtracted from the PCIA in order to avoid double counting, as the costs of CTC-eligible contracts are also included in the TPC.

i. Total Portfolio Cost

The TPC is based on the IOUs' forecasted cost in meeting the electricity load requirements of bundled service customers, based on production cost modelling that relies on IOU supply portfolio inputs and forecasts of load and other factors. (Though certain costs are not included under the TPC per D.11-12-018, such as contracts of less than one year in duration and California Independent System Operator charges.)

Econometric models are used to establish relationships between retail sales and various weather, economic, demographic and other factors that impact electricity usage. Examples include employment, building floor stock, and energy efficiency and self-generation. Forecasts of retail load are based on weather conditions derived from an average of historic values, and anticipated economic and other trends. Forecasts of retail load that has or will depart to DA or CCA service are then subtracted.

The methodologies used to forecast CCA departing load vary by IOU. SCE and SDG&E base this forecast on whether or not a CCA has submitted a Binding Notice of Intent. The CPUC, in D.15-10-031, recently accepted PG&E's methodology that additionally incorporates load departures for potential CCAs based on various probability factors.

IOU revenue requirements are forecasted based on simulations using a production cost model (such as PLEXOS or PROSYM). These models capture physical generation unit constraints and CAISO market rules (including import/export restrictions), and forecast CAISO market prices and IOU revenue requirements by simulating the optimized least-cost dispatch of generation units (LCD, i.e. units are dispatched when the marginal operating cost is less than the market price of power) and Monte Carlo simulations of forced outages. Inputs include the IOU supply portfolios[2] (with any contractual limitations therein), IOU load forecasts, and forecasts of system load, planned outages, hydroelectric availability and natural gas, Greenhouse Gas, and forward power broker prices,.

For the ERRA proceedings, a single scenario is selected to forecast IOU revenue requirements for the setting of retail generation rates and the TPC for use in the PCIA calculation. The IOU's revenue requirement, minus certain costs per D.11-12-018, is divided by the total MWh of forecasted bundled service customer load to yield the TPC.

Vintaging of Supply Portfolios

The TPC is vintaged such that customers departing before July 1 of a given year are assigned the previous year's vintage, and customers departing after July 1 are assigned the current year's vintage. This vintaging process ensures that the portfolio of supply resources for which departing load customers are responsible is held constant, set during the period during which the customers depart IOU basic service. The time at which an individual resource is considered committed for vintaging purposes is defined as the date a contract is signed or construction begins.

Term of Cost Recovery

The length of cost recovery allowed for each contract or asset under the TCP varies; for example, cost recovery is guaranteed for the length of the contract for RPS eligible renewables (i.e. 20-25 years, typically) but typically only out for 10 years for non-renewable resources. If the IOUs believe a cost recovery period extension is appropriate and necessary for specific resources that exceed these limits, they can make such requests under the provisions of D.04-12-048.

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[2] Consisting of utility-owned generation (UOG), purchased power resources (including Qualifying Facility and Renewable Portfolio Standard contracts), bilateral and interutility contracts, and generic contracts of anticipated future purchases.

ii. Market Price Benchmark

The Market Price Benchmark is the IOU's supply portfolio valued at the forecasted estimate of the price of electricity for the forthcoming year. It is used in the PCIA calculation as a proxy for the average price that the IOU should expect to receive for sales of power in excess of the volume required to serve its bundled service customer base.

The current methodology for calculating the MPB relies on a month's worth of on- and off-peak 12-month forward price strips (as reported by Platt's Megawatt Daily) that are averaged and weighted based on bundled load factors, adders for Renewable Portfolio Standard (RPS or "Green Adder") and Resource Adequacy (RA) valuations calculated by the CPUC Energy Division, and line losses adjustments.

Both the RPS and RA adders are calculated by the Energy Division based on information supplied by the IOUs in their October 1 informational filings, per Resolution E-4475, and given to the IOUs to calculate revised PCIA estimates in November. The RPS adder is weighted in the following manner: 68% based on the average cost of the three IOUs' RPS resources and 32% based on the average premium paid by renewable contracts in the Western United States (from the most recent 12 months of data compiled by US DOE surveys and compiled by the National Renewable Energy Laboratory). Because the RPS and RA adders are partly a function of the IOU's resource portfolio, the portfolios included in the adders are vintaged in the same fashion as the TPC.

The MPB methodology was detailed in D.06-07-030 – Appendix 1 and clarified in Commission Resolution E-4475 – Exhibit A (10 March 2012) after D.11-12-018 introduced the weighted averaging of market price forecasts and the RPS and RA adders.

The total number of MWh in the IOU's supply portfolio is multiplied by this forecasted price to yield the MBP for the PCIA calculation.

B. Question 2: Do you believe the current PCIA methodology should be changed? If so, how and why? Please be as specific as possible.

Yes. Because the PCIA relies on mathematical forecasts as a proxy for the actual above- or below-market costs of the IOUs' supply portfolios, it is subject to forecast error and as such it represents a flawed estimate of indifference costs. While the current methodology may be adequate for small amounts of departed load (as in the case of current CCAs, which are a relatively small fraction of IOU load), it is not sufficiently accurate to preserve bundled or CCA customer indifference in the case of significant volumes of departing load.

1. Significant Volumes of Load Departing to CCA

With the participation of all eligible cities, the County of Los Angeles' CCA at full enrollment would be the largest public power enterprise in the nation, accounting for approximately 40% of Southern California Edison's ("SCE") load requirements. Statewide, local governments and governmental associations in twenty-four counties are actively operating or considering launching CCA programs over the next several years. With the existing CCA programs,[3] these initiatives at full enrollment represent approximately two-thirds of IOU electricity load requirements.[4]

i. Practical Limitations of the PCIA Methodology

In this context, the PCIA as a mechanism will likely become unworkable; as the volume

[3] Sonoma Clean Power, Marin Clean Energy and Lancaster Choice Energy; note that Marin Clean Energy also serves cities in the counties of Napa and Contra Costa, and that CleanPowerSF (San Francisco) is expected to launch shortly.

[4] Note that numerous interested cities active within each county are not listed here): Los Angeles County; Redwood Coast Energy Authority (Humboldt County); Silicon Valley Community Choice Energy Partnership (SVCCEP, Santa Clara County and most cities except for San Jose); the City of San Jose; Peninsula Clean Energy (San Mateo County); Central Coast Community Choice Energy (Counties of Santa Barbara, Ventura and San Luis Obispo); Monterey Bay Community Power (Counties of Santa Cruz, Monterey and San Benito); Alameda County; Contra Costa County; Butte County; City of Davis (in Yolo County); Western Riverside Council of Governments (WRCOG); San Bernardino Associated Governments (SANBAG); Lake County; Mendocino County; Solano County, cities in Napa County and the City of San Diego.

of departing load increases, any degree of inaccuracy in the mathematical calculation of the difference between an average IOU portfolio cost for a given vintage to a forecasted market price benchmark for a given period of time will increasingly result in a significant financial burden being carried by either the CCAs or the IOUs. In this event, the regulatory oversight process as well as the timeliness and predictability of subsequent true-up adjustments may prove unduly burdensome in for the CCAs, IOUs and the CPUC.

SCE and SDG&E's concerns on the limitations of the PCIA are referenced in D. 08-09-012. Specifically, that Decision references an assertion that the current PCIA mechanism would need to be revised after CCA penetration exceeds the maximum historic DA penetration in the IOU territory:

> "SCE believes that the current methodology for determination of a market price benchmark is reasonable as long as the load departure does not increase significantly above that seen in the post-2001 period. If it does increase significantly, SCE indicates it may ask the Commission to revisit the issue. SDG&E also states that it is not clear that the benchmark would be appropriate in the future should DA reopen or significant load migrates via CCA."

This limit will be exceeded in PG&E's territory over the course of this year (2016), according to the IOU's current projections as approved by D.15-10-031. In addition, if either LA County or the City of San Diego were to launch a CCA, at full enrollment each program would account for approximately 40% of the incumbent IOU's load requirements (i.e. far exceeding the historic penetration of DA). Given the momentum in SCE and SDG&E service territories, it is important to begin re-evaluating the PCIA purpose and/or need in these territories as soon as possible.

ii. Structural Considerations for CCA Power Supply Contracting

As the volume of load departing to CCA service grows, at some point CCAs will need to purchase power and dispatch facilities currently owned by or under contract with the IOUs. CCAs to date have procured power several months in advance of program launch and prudently minimized market price exposure - which is especially critical during the initial period of operations after program launch, prior to the point at which the CCA has been able to build up a reserve fund. Depending on the timing of the launch of an individual CCA versus the overall penetration of departing load statewide, the CCA may or may not be able to procure power from resources outside the control of an IOU. This may become a barrier to the practical launch of new CCA programs, or the gradual enrollment of customers in a large CCA program.

2. Innovative Solutions Are Required

In the context of significant volumes of load departing to CCA service, there is a need to define a fundamentally new mechanism and process that minimizes or avoids the potential mathematical and practical challenges that would be imposed by the current PCIA methodology and underlying assumptions. Revising the PCIA calculations alone would not resolve the issues alluded to under "Structural Considerations for CCA Power Supply Contracting", and regardless, the entire concept of relying on a mathematical forecast of indifference amounts may be practically unworkable given the expected volume of load departing to CCA service over the near term – as explained under "Practical Limitations of the PCIA Methodology".

In other words, rather than focusing exclusively on how best to calculate and collect a non-bypassable charge, the workshop should also initiate a discussion regarding the establishment of a new framework altogether that (1) ensures State policy goals are met while (2) precluding cost-shifting between CCA, Direct Access and IOU bundled customers and (3) facilitates the scale of transition to public power represented by the current exploration of CCA statewide and by the County of Los Angeles in particular.

C. Question 3: How should the CPUC address the potential departure from bundled service of a very large load, such as the City of San Diego or County of Los Angeles? Would transferring contractual responsibility from an IOU to a CCA be an option?

As explained in the response to Question 1 above, given the fact that twenty-four counties are currently in some stage of exploration of CCA, the issues with the current PCIA methodology which a "very large" CCA like the County would face in enrolling all eligible customers will likely soon be shared by all CCAs.

1. A Solution Commensurate to the Problem

The County proposes that a process be established to regulate and negotiate the transfer contracts, PCIA and CAM (Cost Allocation Mechanism) cost recovery authorities, and Provider of Last Resort (POLR) responsibilities in operations and planning activities from the IOUs to CCAs.

This poses equity issues (in terms of cost, commodity price risk, renewable content, greenhouse gas impacts and other factors) that would be inherent within the unbundling of an IOU's portfolio for transference of a portion of the portfolio to one CCA versus another (or to an association of CCAs).

i. Responsibilities of CCAs

This would require substantial leadership and sophistication on the part of the CCA industry. To provide a sufficient degree of scale and stability, "regional energy" Joint Power Agencies ("RE-JPAs") composed of CCAs could be formed to assume POLR responsibilities and to provide a full suite of power operations and Integrated Resource Planning services optimized across multiple CCA territories. This strategy could be informed by the success of the Northern California Power Authority (NCPA) and Southern California Public Power Authority

(SCPPA), as JPAs that perform similar functions for their municipal utility members. To a large extent, individual CCAs would be able to retain control of their unique portfolio strategies (choice of power mix) and local energy programs – both of which would be enhanced by this new level of operational sophistication - as well as rate-setting.

ii. Commission Authorities

Whether this proposal is within the Commission's authority to enact should be determined. The Commission has broad authority under Article XII of the California Constitution, sections 701 and 728 of the Public Utilities Code, and prior precedent.

2. Provider of Last Resort (POLR)

In any restructured market (i.e. where customers may receive electricity commodity service from an entity that is not the distribution utility), there is a "provider of last resort" (POLR). This entity is responsible for ensuring that there is sufficient generation capacity to serve any and all customers. In California, the current POLRs are the IOUs.

The primary function of the POLR is to ensure system reliability as customers switch back and forth between load serving entities, either on an individual basis or in the event that a CCA or a power marketer ceases operations for any reason or otherwise exits the market – thereby defaulting a significant customer base back to basic service.

i. Recent Discussions of the POLR Responsibility in the Context of CCA Growth

The Provider of Last Resort issue was raised by PG&E in its December 2014 Long Term Procurement Plan (LTPP) filings:

> "The Commission and California policy makers should consider how to ensure that all LSEs are prepared to reliably service their load on a long-term basis, and that there is appropriate compensation and cost recovery for entities that act as a provider of last

resort."[5]

In the subsequent July 2015 decision, the Commission noted that MCE had also stated that "CCA development had affected the provider of last resort landscape" and that this impacted the LTPP, but ruled that POLR issues were outside of the scope of the proceeding.[6]

ii. Consideration of the Broader Context of Power Planning & Operations

The apparent near-term shift of large volumes of load from the IOUs to the CCAs is happening as California is entering a critical period of power planning and investment, with corresponding changes in regulation and market design; in brief:

1. Sixteen power plants totaling 17,500 megawatts of capacity are slated to retire in the near-term due to environmental 'Once Through Cooling' restrictions, while the power sector invests upwards of $100 billion into primarily variable renewable resources (wind and solar) to achieve the 50% by 2030 Renewable Portfolio Standard;
2. To ensure the power grid remains stable as it integrates increasing volumes of variable renewable generation, new "flexible" capacity products, markets and procurement mandates are being created and the wholesale transmission power markets are being expanded to integrate with neighboring regional markets;
3. Deployments of distributed generation, demand response, energy storage, energy efficiency and electric vehicles are accelerating dramatically and being integrated into transmission and distribution grid planning and operations;
4. Retail rates are evolving to 'time of use' and 'dynamic' structures that vary electricity prices by the time of day, in order to align the prices that customers pay with the actual

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[5] See Pacific Gas and Electric Company's (U 39 E) Proposed 2014 Bundled Procurement Plan

[6] See Decision 15-10-031 at page 45

cost drivers of wholesale supply and distribution infrastructure investments (and thus enable distributed energy resources to offset these costs in a more targeted fashion);

5. The proper role of the IOUs is under debate; their regulated business models may shift from a 'cap-ex cost plus' model (i.e. a guaranteed return on capital invested into infrastructure, which poses a conflict of interest to the spread of distributed energy resources) to one that bases the IOUs' returns on achieving certain benchmarks (e.g. reliability metrics and distributed energy resource penetration).
6. The changes above have provoked a discussion regarding the ability of current modeling tools and methodologies to appropriately capture many of the above considerations.

Given the above context, in which the power industry in California is entering into an apparent 'paradigm-shift', it will be increasingly challenging to perform the responsibilities of the POLR.

iii. Shift to Integrated Resource Planning

To better manage these challenges, the Legislature has imposed Integrated Resource Planning (IRP) requirements on the IOUs, and the corresponding planning processes at the CPUC, California Independent System Operator (CAISO) and California Energy Commission (CEC) are being more closely aligned with one another. Refer to Appendix A for a diagram of this process alignment.

The Commission has limited jurisdictional authority over the power planning and operations of CCAs. SB 350 requires CCAs to conduct IRPs, but the CPUC has no jurisdiction over the methodologies employed; approval of an IRP remains with the governing body of the CCA, which then is required to submit the plans to the CPUC for certification.

To credibly be able to assume POLR responsibility and the authority to recover costs on a non-bypassable basis, CCAs will need to be better integrated into various planning processes at the CAISO, CPUC and CEC and demonstrate competence in conducting Integrated Resource Planning. To optimize IRP processes across multiple CCA territories will require formal coordination amongst individual CCAs.

3. Power Charge Indifference Adjustment Reciprocity for CCAs

There is an inherent problem in expecting the CCA industry at scale to engage in significant long-term contracting under the current regulatory framework, in that the CCA's customer base has the ability to opt-out of the program and avoid any repayment obligations that stem from these long-term contracts. Key risk factors in this regard include:

1. Whether the CCA's financial planning, risk management policies, operational sophistication and reserve fund is sufficient to 1) maintain competitive rates and 2) remain financially solvent in the event of protracted, adverse market conditions;
2. Whether and to what extent Direct Access is reopened in California;
3. How the penetration of further CCA programs affects wholesale market conditions and the CCA's cost of service.
4. The extent to which the real or perceived risk of the above factors preclude project developers from signing long-term contracts with CCAs at some point in the future.

SB 350 imposed the requirement that all CCAs must source at least 65% of their RPS-eligible supply portfolios from resources that they own or procure under contracts of 10 years of duration or more by 2021. This mandate should not pose undue difficulties for the CCAs that launch several years in advance of this date. Those CCAs will have sufficient time to build up a reserve fund sufficient to ensure program stability and to execute the requisite long-term contracts. For CCAs that launch closer to or after the 2021 date, this requirement may present an obstacle, absent the implementation of the approach contemplated in these responses. However, there are several years in which to seek a change in statute to allow for a grace period for new CCAs, as well as further clarification from the Commission on the matter.

Absent CCAs gaining the authority to recover costs from customers on a non-bypassable basis similar to the IOUs, it remains to be seen to what extent a CCA can hedge its market exposure or play a comparable role in stabilizing electricity prices as the IOUs currently do through long-term contracts.

i. Marin Clean Energy and PG&E Statements Regarding CCA Cost Recovery

In Marin Clean Energy's Revised Implementation Plan (2014), the CCA stated that non-bypassable cost recovery (along the lines of the PCIA) may be possible by imposing "exit fees" on departing customers. In a recent response to a data request by MCE leading up to this workshop, PG&E stated:

> Marin Clean Energy ("MCE") has adopted a similar concept to allow for the potential recovery of above-market costs from its customers who return to utility service or elect to receive service from a DA provider. MCE referred to its nonbypassable charge as a "Cost Recovery Charge" in its most recent Revised Community Choice Aggregation Implementation Plan and Statement of Intent dated July 18, 2014 ("Revised Implementation Plan") (marked as Exhibit PG&E-5 in PG&E's 2016 Energy Resource Recovery Account ("ERRA") Forecast application proceeding). Currently, MCE's Cost Recovery Charge is zero, but this may be changed by the MCE board during MCE's annual ratemaking process. See Revised Implementation Plan at p. 45.

The workshop should discuss and request Commission clarification on the ability of CCAs to recover costs on a fully non-bypassable basis in the manner anticipated by MCE.

4. Cost Allocation Mechanism (CAM) Reciprocity for CCAs

The Cost Allocation Mechanism (CAM) was established in 2005 by D. 04-12-048 to recover costs from resources required to meet resource adequacy (i.e. grid stability) requirements. CAM recovers costs only from the capacity payments of an eligible generating facility. The capacity share is calculated as the difference between the cost of the facility and revenues from power sold. Cost recovery under the CAM mechanism is guaranteed for the duration of the contract.

While the RA procurement requirements of CCAs are offset by the portion of the capacity paid for by their customers, the CAM mechanism requires IOUs to effectively make long-term procurement decisions on behalf of CCA customers. As such, CAM compromises the local political mandate of CCAs to fully determine their community's energy future. This issue promises to be a growing source of tension between IOUs and CCAs over time, as the increasing penetration of variable renewable resources (such as wind and solar) under the RPS increases and requires flexible capacity investments to integrate.

To be able to fully determine their own power supply portfolios and costs, CCAs will need to assume these responsibilities and authorities. There is some precedent for this discussion in recent CPUC communications and statute.

i. CPUC Whitepaper on CAM Authority for CCAs

CPUC staff released a whitepaper in September 2014[7] to engender discussion over whether CCAs should be able to recoup reliability-related investments from all benefitting ratepayers (i.e.

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[7] Refer to California Public Utilities Commission Policy & Planning Division, "Cost Allocation Mechanism", 24 September 2014, available from [http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDCAMwhitepaper20140924forpub.pdf]

IOU and DA customers as well as their own customers) under the Cost Allocation Mechanism (CAM) as the IOUs do currently. It was anticipated that this would require that CCAs engage in relevant CPUC proceedings as the forum in which investment decisions are reviewed and authorized.

ii. SB 350 Implications for CAM Authority for CCAs

Senate Bill 350, passed in September 2015, also presents opportunities in this regard. Namely, Public Utilities Code Section 454.51 was expanded to mandate (emphasis added):

> The commission shall do all of the following:
>
> (a) **Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner.** The portfolio shall rely upon zero carbon-emitting resources to the maximum extent reasonable and be designed to achieve any statewide greenhouse gas emissions limit established pursuant to the California Global Warming Solutions Act of 2006 (Division 25.5 (commencing with Section 38500) of the Health and Safety Code) or any successor legislation.
>
> …
>
> (c) **Ensure that the net costs** of any incremental renewable energy integration resources **procured by an electrical corporation** to satisfy the need identified in subdivision (a) **are allocated on a fully nonbypassable basis** consistent with the treatment of costs identified in paragraph (2) of subdivision (c) of Section 365.1.
>
> …
>
> (d) **Permit community choice aggregators to submit proposals for satisfying their portion of the renewable integration need identified in subdivision (a). If the commission finds this need is best met through long-term procurement commitments**

for resources, community choice aggregators shall also be required to make long-term commitments for resources. The commission shall approve proposals pursuant to this subdivision if it finds all of the following:

(1) The resources proposed by a community choice aggregator will provide equivalent integration of renewable energy.

(2) The resources proposed by a community choice aggregator will promote the efficient achievement of state energy policy objectives, including reductions in greenhouse gas emissions.

(3) Bundled customers of an electrical corporation will be indifferent from the approval of the community choice aggregator proposals.

(4) All costs resulting from nonperformance will be borne by the electrical corporation or community choice aggregator responsible for them.

Open Questions for Implementation of SB 350

While this language appears to support any CCA that wishes to contract for reliability-related investments to integrate and balance renewable resources, it also contains key questions that require clarification by the CPUC, specifically:

1. While subdivision (c) specifically affords "electrical corporations" the ability to allocate and recover costs on a non-bypassable basis across all benefitting customers (using the CAM mechanism), will CCAs be afforded the same authority? Note that the

aforementioned CPUC staff white paper highlighted the possibility that CAM reciprocity may be able to be extended to CCAs under extant regulatory authority.[8]

2. In the event that CCAs procure reliability resources that benefit both bundled service and CCA customers, will subsection (d)(3) preclude the CCA from allocating costs to utility customers? Or will the CPUC interpret this subsection as meaning that utility customers are indifferent to such charges, as the utility would otherwise have to procure such resources?

D. Question 4: Should Direct Access (DA) customers and Community Choice Aggregator (CCA) customers be treated differently vis-à-vis the PCIA? If so, why and how?

Yes, for three primary reasons: (1) CCAs are local government agencies and Energy Service Providers (ESPs) are private, for profit companies; (2) CCAs are stable, long-term entities designed to achieve public policy goals for large territories while DA primarily serves large customers that are seeking lower cost supply (with potentially higher exposure to market price and counterparty default risk); and (3) DA service is capped while CCAs are not, and the volume of load expected to depart to CCA service in the near term is extremely high – consequently, the solution proposed in these responses is for CCAs to become the POLR and gain cost recovery authorities commensurate with their responsibilities and policy goals.

As such, it inherently odd that CCA and ESPs are under similar regulations to begin with. As context, CCAs in the rest of the country are mostly short-lived retail aggregations run by ESPs. The CCAs are established primarily to lower customer rates, and after the initial term with

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[8] Refer to California Public Utilities Commission Policy & Planning Division, "Cost Allocation Mechanism", 24 September 2014, available from: [http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPDCAMwhitepaper20140924forpub.pdf]

the ESP expires, the programs are often suspended or dissolved (depending on market conditions). In contrast, the CCA program design which has evolved in California has created government entities that build up reserve funds sufficient to ensure the stability of the program over the long-term. Consequently, the CCAs in California are able to execute long-term (20-25 year) Power Purchase Agreements for the construction of new sources of renewable energy and capacity, implement Demand Side Management programs and build local staff capacity; additionally, CCAs are planning to leverage other inherent benefits, such as tax-exempt municipal financing.

In other words, the CCA industry in California is breaking new ground in this regard, in that what was expected to be a potentially unstable retail program run by an ESP has evolved into a new form of stable government agency with a strong public purpose.

Consequently, the corresponding legal and regulatory framework is still evolving to catch up; this explains why, in many respects, CCAs in California inhabit a regulatory 'grey area' when it comes to power procurement and planning authorities, particularly in regards to cost recovery.

E. Question 5: Can transparency regarding the calculation of the PCIA be increased while protecting valid interests in keeping certain information confidential?

Yes. Owing to the nature of the program design that has evolved in California, CCAs are stable government agencies with strong public purpose mandates. In order to implement the transition of authorities and contracts from IOUs to CCAs that is proposed in these responses, it would be necessary for CCAs to have access to IOU supply portfolio information that is currently held confidential. Prior to this transition, access to confidential information would be required to verify that the IOUs are calculating the PCIA correctly and only seeking to recover unavoidable above market costs.

Doing so would not violate extant confidentiality restrictions because CCAs would not use the confidential information to impact the IOUs' market price for electricity. CCAs are nonprofit government agencies that do not engage in speculative trading activities, sell power to the IOUs, or seek to disadvantage bundled service customers in any other manner.

1. Extant Confidentiality Restrictions

D.06-06-066 implemented regulations to ensure the confidentiality of market sensitive portions of IOU procurement plans in accordance with Public Utilities Code Section 454.5(g). It stated that "Confidentiality protections are essential to avoid a repetition of electricity market manipulation." Consequently, the Decision established a materiality standard that "Only information that would have a material impact on a procuring party's market price for electricity is protected" and mandated that "The party producing the data always bears the burden of proof." Two classifications of entitles were defined: "it is appropriate and lawful under § 454.5(g) to make distinctions between non-market participants and market participants in determining whether to grant access to confidential data" with the market participants only able to access confidential information in very narrow circumstances:

> 3) A person or entity that meets the criteria of 1) above is nonetheless not a market participant for purpose of access to market sensitive data unless the person/entity seeking access to market sensitive information has the potential to materially affect the price paid or received for electricity if in possession of such information. An entity will be considered not to have such potential if:
>
> > a) the person or entity's participation in the California electricity market is *de minimis* in nature. In the resource adequacy proceeding (R.05-12-013) it was determined in D.06-06-064 § 3.3.2 that the resource adequacy requirement should be rounded to the nearest megawatt (MW), and load serving entities (LSEs) with local resource adequacy requirements less than 1 MW are not required to make a

showing. Therefore, a *de minimis* amount of energy would be less than 1 MW of capacity per year, and/or an equivalent of energy; and/or

b) the person or entity has no ability to dictate the price of electricity it purchases or sells because such price is set by a process over which the person or entity has no control; and/or

c) person or entity is a cogenerator that consumes all the power it generates in its own industrial and commercial processes.

III. CONCLUSION

The issues summarized herein recognize that the CCA industry is fundamentally changing the structure of the power industry in California. The County proposes that a process be established to transfer contracts, PCIA and CAM (Cost Allocation Mechanism) cost recovery authorities, and Provider of Last Resort (POLR) responsibilities in operations and planning activities from the IOUs to CCAs.

To provide a sufficient degree of scale and stability, "regional energy" Joint Power Agencies ("RE-JPAs") composed of CCAs could be formed to (1) assume POLR responsibilities and (2) provide a full suite of power operations and Integrated Resource Planning services optimized across multiple CCA territories; this arrangement would be similar to the one between municipal utilities and the Northern California Power Authority (NCPA) and Southern California Public Power Authority (SCPPA).

Effectively clarifying the range of issues raised herein will require substantial input and clarification by the Commission and stakeholders; we note that Southern California Edison has recently cautioned the Commission that:

> If the Commission wishes to revisit the issue of how to maintain bundled service customer indifference in the face of a growing and changing departing load customer

environment, it should do so holistically, and not piecemeal starting in one IOU's ERRA Forecast proceeding.[9]

The County of Los Angeles agrees, and recommends that a separate proceeding be established to ensure that a solution commensurate to this challenge be implemented in a timely fashion.

Respectfully submitted,

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[9] See Southern California Edison Company's (U-338-E) Reply Brief in Response to Assigned Commissioner's Ruling Amending Scope of Phase 2 and Setting Out Briefing Schedule, at page 3.

APPENDIX A: PLANNING PROCESS ALIGNMENT AT CPUC, CAISO AND CEC

This diagram was developed in 2015 for discussion purposes for the More Than Smart Working Group, and should not be taken as an accurate representation of all the details of the various processes. In particular, the "Biennial DPP" track is only conceptual at this time and has not been formally established by the CPUC.